

Appendix F

Generic Environmental Impact Statement Environmental Issues Not Applicable to Oyster Creek Nuclear Generating Station

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Table F-1 lists those environmental issues listed in the *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) (NRC 1996, 1999)^(a) and Title 10, Part 51, of the *Code of Federal Regulations* (10 CFR Part 51), Subpart A, Appendix B, Table B-1, that are not applicable to Oyster Creek Nuclear Generating Station (OCNGS) because of plant or site characteristics.

Table F-1. GEIS Environmental Issues Not Applicable to OCNGS

ISSUE—10 CFR Part 51, Subpart A, Appendix B, Table B-1	Category	GEIS Sections	Comment
SURFACE-WATER QUALITY, HYDROLOGY, AND USE (FOR ALL PLANTS)			
Altered thermal stratification of lakes	1	4.2.1.2.2; 4.4.2.2	OCNGS does not use surface water from lakes.
Water-use conflicts (plants with cooling ponds or cooling towers using makeup water from a small river with low flow)	2	4.3.2.1; 4.4.2.1	The OCNGS cooling system does not use cooling ponds or cooling towers.
AQUATIC ECOLOGY (FOR ALL PLANTS)			
Premature emergence of aquatic insects	1	4.2.2.1.7, 4.4.3	OCNGS is located on an estuary and cooling water is too saline to support aquatic insects.

(a) The GEIS was originally issued in 1996. Addendum 1 to the GEIS was issued in 1999. Hereafter, all references to the "GEIS" include the GEIS and its Addendum 1.

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Table F-1. (contd)

ISSUE—10 CFR Part 51, Subpart A, Appendix B, Table B-1	Category	GEIS Sections	Comment
AQUATIC ECOLOGY (FOR PLANTS WITH COOLING-TOWER-BASED HEAT-DISSIPATION SYSTEMS)			
Entrainment of fish and shellfish in early life stages	1	4.3.3	OCNGS does not use a cooling tower.
Impingement of fish and shellfish	1	4.3.3	OCNGS does not use a cooling tower.
Heat shock	1	4.3.3	OCNGS does not use a cooling tower.
GROUNDWATER USE AND QUALITY			
Groundwater-use conflicts (potable and service water, and dewatering; plants that use >100 gpm)	2	4.8.1.1; 4.8.2.1	OCNGS does not use >100 gpm of groundwater.
Groundwater-use conflicts (plants using cooling towers withdrawing makeup water from a small river)	2	4.8.1.3; 4.4.2.1	OCNGS does not use a cooling tower.
Groundwater-use conflicts (Ranney wells)	2	4.8.1.4	OCNGS does not use Ranney wells.
Groundwater-quality degradation (Ranney wells)	1	4.8.2.2	OCNGS does not use Ranney wells.
Groundwater-quality degradation (cooling ponds in salt marshes)	1	4.8.3	OCNGS does not use a cooling pond.
Groundwater-quality degradation (cooling ponds at inland sites)	2	4.8.3	OCNGS does not use a cooling pond.
TERRESTRIAL RESOURCES			

Table F-1. (contd)

ISSUE–10 CFR Part 51, Subpart A, Appendix B, Table B-1		Category	GEIS Sections	Comment
1	Cooling-tower impacts on crops and	1	4.3.4	OCNGS does not use a
2	ornamental vegetation			cooling tower.
3	Cooling-tower impacts on native plants	1	4.3.5.1	OCNGS does not use a
				cooling tower.
4	Bird collisions with cooling towers	1	4.3.5.2	OCNGS does not use a
				cooling tower.
5	Cooling pond impacts on terrestrial	1	4.4.4	OCNGS does not use a
6	resources			cooling pond.
HUMAN HEALTH				
8	Microbial organisms (occupational health)	1	4.3.6	OCNGS does not use a
				cooling tower.
9	Microbial organisms (public health)	2	4.3.6	This issue is related to heat-
10	(plants using lakes or canals, or cooling			dissipation systems that are
11	towers or cooling ponds that discharge to			not installed at OCNGS.
12	a small river).			

F.1 References

10 CFR Part 51. *Code of Federal Regulations*, Title 10, *Energy*, Part 51, “Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions.”

U.S. Nuclear Regulatory Commission (NRC). 1996. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants*. NUREG-1437, Vols. 1 and 2, Washington, D.C.

U.S. Nuclear Regulatory Commission (NRC). 1999. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Main Report*, “Section 6.3 – Transportation, Table 9.1, Summary of Findings on NEPA Issues for License Renewal of Nuclear Power Plants, Final Report.” NUREG-1437, Vol. 1, Addendum 1, Washington, D.C.

Appendix G

NRC Staff Evaluation of Severe Accident Mitigation Alternatives for Oyster Creek Nuclear Generating Station in Support of License Renewal Application

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NRC Staff Evaluation of Severe Accident Mitigation Alternatives for Oyster Creek Nuclear Generating Station in Support of License Renewal Application

G.1 Introduction

AmerGen Energy Company, LLC (AmerGen), submitted an assessment of severe accident mitigation alternatives (SAMAs) for Oyster Creek Nuclear Generating Station (OCNGS) as part of the Environmental Report (ER) (AmerGen 2005). This assessment was based on the most recent OCNGS Probabilistic Risk Assessment (PRA) available at that time, a plant-specific offsite consequence analysis performed with the MELCOR Accident Consequence Code System 2 (MACCS2) computer code, and insights from the OCNGS Individual Plant Examination (IPE) (GPU 1992) and Individual Plant Examination of External Events (IPEEE) (GPU 1995). In identifying and evaluating potential SAMAs, AmerGen considered SAMAs that addressed the major contributors to core damage frequency (CDF) and large early release frequency (LERF) at OCNGS, as well as SAMA candidates for other operating plants that have submitted license renewal applications. AmerGen identified 136 potential SAMA candidates. This list was reduced to 37 unique SAMA candidates by eliminating SAMAs that are not applicable to OCNGS because of design differences, required extensive changes that would involve implementation costs known to exceed any possible benefit, have already been implemented, are of low benefit, or are addressed by a similar SAMA. AmerGen assessed the costs and benefits associated with each of the potential SAMAs and concluded that several of the candidate SAMAs evaluated would be cost-beneficial.

On the basis of a review of the SAMA assessment, the NRC issued a request for additional information (RAI) to AmerGen by letter dated November 9, 2005 (NRC 2005). Key questions concerned changes to the Level 1 and Level 2 PRA model since the IPE, the PRA self-assessment performed in 2004, the multiplier used to account for external events, the reanalysis of the fire risk subsequent to the IPEEE; clarification/information on several specific candidate SAMAs, and the evaluation of combinations of potentially cost-beneficial SAMAs. AmerGen submitted additional information by letters dated January 9, 2006 (AmerGen 2006a), and March 15, 2006 (AmerGen 2006b). In the responses, AmerGen provided a listing of the major modifications made to the Level 1 model since the IPE, a description of the current Level 2 model, a description and summary results of the self-assessment, justification for the use of the multiplier for external events, information regarding the updated fire PRA, specific

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requested information for the SAMAs of interest, and the results of combining selected potentially cost-beneficial SAMAs. AmerGen's responses addressed the NRC staff's concerns.

An assessment of SAMAs for OCNGS is presented below.

G.2 Estimate of Risk for OCNGS

AmerGen's estimates of offsite risk at OCNGS are summarized in Section G.2.1. The summary is followed by the NRC staff's review of AmerGen's risk estimates in Section G.2.2.

G.2.1 AmerGen's Risk Estimates

Two distinct analyses are combined to form the basis for the risk estimates used in the SAMA analysis: (1) the OCNGS Level 1 and 2 PRA model, which is an updated version of the IPE (GPU 1992), and (2) a supplemental analysis of offsite consequences and economic impacts (essentially a Level 3 PRA model) developed specifically for the SAMA analysis. The SAMA analysis is based on the most recent OCNGS Level 1 and 2 PRA model, referred to as the 2004B PRA model. The scope of the OCNGS PRA does not include external events.

The baseline CDF for the purpose of the SAMA evaluation is approximately 1.1×10^{-5} per year. The CDF is based on the risk assessment for internally initiated events. AmerGen did not include the contribution from external events within the OCNGS risk estimates; however, it did account for the potential risk reduction benefits associated with external events by doubling the estimated benefits for internal events. AmerGen also utilized a recently completed fire PRA to assess the risk reduction for several fire-related SAMAs. This is discussed further in Sections G.2.2 and G.6.2.

Table G-1 provides the breakdown of the CDF by initiating event. As shown in this table, events initiated by loss of offsite power (LOOP) are the dominant contributors to CDF. Although not separately reported, station blackout sequences contribute about 43 percent of the total internal events CDF (4.48×10^{-6} per year), while anticipated transient without scram (ATWS) sequences are small contributors to CDF (2.89×10^{-7} per year).

The current OCNGS Level 2 PRA model represents a significant change from the somewhat simplistic analysis that was utilized in the IPE. This update is a full Level 2 model that is stated to meet standard industry practice. The Level 1 results are initially characterized by 13 accident sequence functional classes. A separate containment event tree is used for each of the Level 1 accident classes to describe the response of the containment. The linked Level 1/Level 2 end states are then grouped into release categories based on magnitude and timing of the expected releases. The resulting release categories are then reduced to 10 consequence categories for use in consequence analyses. The fission product release fractions are obtained from the

Table G-1. OCNGS Core Damage Frequency

Initiating Event	CDF (per year)	% Contribution to CDF
Loss of offsite power (LOOP)	4.2×10^{-6}	40
Manual shutdown	6.8×10^{-7}	7
Medium loss-of-coolant accident (LOCA)	6.5×10^{-7}	6
Reactor trip	5.8×10^{-7}	6
Loss of 4160-volts alternating current (VAC) Bus 1C	5.3×10^{-7}	5
Condenser bay area feedwater flood	4.9×10^{-7}	5
Loss of 4160-VAC Bus 1D	4.5×10^{-7}	4
Turbine trip	3.5×10^{-7}	3
Loss of circulating water	3.5×10^{-7}	3
Loss of feedwater	3.4×10^{-7}	3
Others	1.9×10^{-6}	18
Total CDF	1.05×10^{-5}	100

results of analyses of representative sequences for each consequence category by using version 4.0.5 of the Modular Accident Analysis Program (MAAP). The results of the Level 2 PRA are a set of consequence categories with their respective frequency and release characteristics. The results of this analysis for OCNGS are provided in Tables F-6 and F-7 of the ER (AmerGen 2005).

The offsite consequences and economic impact analyses use the MACCS2 code to determine the offsite risk impacts on the surrounding environment and public. Input for these analyses includes plant-specific and site-specific values for core radionuclide inventory, source term and release characteristics, site meteorological data, projected population distribution (within a 50-mi radius) for the year 2029, emergency response evacuation modeling, and economic data. The magnitude of the onsite impacts (in terms of cleanup and decontamination costs and occupational dose) is based on information provided in NUREG/BR-0184 (NRC 1997a).

In its ER, AmerGen estimated the dose to the population within 50 mi of the OCNGS site to be approximately 36 person-rem per year. The breakdown of the total population dose by containment release mode is summarized in Table G-2. Containment failures within the early time frame (less than 6 hours following declaration of a general emergency) and intermediate time frame (within 6 to 24 hours following declaration of a general emergency) dominate the population dose risk at OCNGS.

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Table G-2. Breakdown of Population Dose by Containment Release Mode

Containment Release Mode	Population Dose (person-rem ^(a) per year)	% Contribution
Early containment failure	23.6	66
Intermediate containment failure	10.3	29
Late containment failure	1.6	4
Bypass	0.4	1
Intact containment	0.1	negligible
Total population dose	36	100
(a) One person-rem = 0.01 person-Sv.		

G.2.2 NRC Staff's Review of AmerGen's Risk Estimates

AmerGen's determination of offsite risk at OCNGS is based on the following four major elements of analysis:

- The Level 1 and 2 risk models that form the basis for the 1992 IPE submittal (GPU 1992) and the external events analyses of the 1995 IPEEE submittal (GPU 1995),
- The major modifications to the IPE model that have been incorporated into the OCNGS PRA,
- The recent reassessment of the fire portion of the IPEEE, referred to as the Fire PRA (FPRA), and
- The MACCS2 analyses performed to translate fission product source terms and release frequencies from the Level 2 PRA model into offsite consequence measures.

Each of these analyses was reviewed to determine the acceptability of AmerGen's risk estimates for the SAMA analysis, as summarized below.

The NRC staff's review of the OCNGS IPE is described in an NRC report dated August 2, 1994 (NRC 1994). On the basis of a review of the IPE submittal, the staff concluded that the IPE submittal met the intent of Generic Letter (GL) 88-20; that is, the IPE was of adequate quality to be used to look for design or operational vulnerabilities. The NRC staff did note, however, that the OCNGS IPE's lack of treatment of preinitiators in the human reliability analysis might limit the IPE's usefulness in other applications. This deficiency was resolved in subsequent PRA

1 updates. The IPE did not identify any severe accident vulnerabilities associated with either core
2 damage or poor containment performance.

3
4 Although no vulnerabilities were identified, 15 modifications to the plant, procedures, and
5 training were identified that had either been implemented, were to be implemented, or were
6 being considered at the time of the completion of the IPE process. Eight of the improvements
7 have not been completed and have been included as candidate SAMAs in the current
8 evaluation (AmerGen 2005).

9
10 Several revisions have been made to the IPE model since its submittal. A comparison of the
11 internal events CDF between the IPE and the 2004B PRA model indicates an increase of
12 approximately 6.8×10^{-6} per year in the total CDF (from 3.69×10^{-6} per year to 1.05×10^{-5} per
13 year). The increase is mainly attributed to many modeling and data changes that have been
14 incorporated since the IPE was submitted. A summary listing of those changes that resulted in
15 the greatest impact on the internal events CDF was provided in the ER (AmerGen 2005) and
16 further discussed in response to an RAI (AmerGen 2006a). Table G-3 summarizes the major
17 changes.

18
19 The IPE CDF value for OCNGS was the lowest CDF value reported in the IPE for boiling-water
20 reactor (BWR) 1/2/3 plants. Figure 11.2 of NUREG-1560 shows that the IPE-based total
21 internal events CDF for BWR 1/2/3 plants ranges from 3×10^{-6} to 5×10^{-5} per year
22 (NRC 1997a). It is recognized that other plants have updated the values for CDF subsequent
23 to the IPE submittals because of modeling and hardware changes. The current internal events
24 CDF results for OCNGS are reasonably consistent with that for plants of similar vintage and
25 characteristics.

26
27 The NRC staff considered the peer review performed for the OCNGS PRA, and the potential
28 impact of the review findings on the SAMA evaluation. In the ER, AmerGen described the
29 previous peer reviews, the most significant of which was the Boiling-Water Reactor Owners
30 Group (BWROG) Peer Review of the 1992 PRA model (i.e., the IPE) conducted in 1997. The
31 BWROG review concluded that the OCNGS PRA can be effectively used to support
32 applications involving relative risk significance. AmerGen stated that all Level A (important and
33 necessary to address before the next regular PRA update) and Level B (important and
34 necessary to address, but disposition may be deferred until the next PRA update) facts and
35 observations from the peer review have been resolved by model changes. AmerGen further
36 stated that no outstanding model issues exist outside the normal PRA maintenance program,
37 and that none are known to have the potential to impact the SAMA conclusions.

38
39 In the ER and subsequent responses to RAIs (AmerGen 2006a,b), AmerGen describes the
40 self-assessment process of the OCNGS PRA model and documentation performed in 2004.
41 This review of the 2001 PRA, against the American Society of Mechanical

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Table G-3. OCNGS PRA Historical Summary

PRA Version	Summary of Changes from Prior model	CDF (per year)
1992	IPE submittal	3.69×10^{-6}
2001A	Resolution of peer review comments Inclusion of internal flooding Data update Level 2 reassessment with simplified large early release frequency (LERF) model	6.27×10^{-6}
2004B	Conversion from RISKMAN to CAFTA software platform Addition of AC and DC initiating events Addition of more detailed modeling of extreme weather and impact on AC power Addition of recirculation pump seal leakage scenario Addition of induced LOOP events for transients and LOCAs Utilized updated plant-specific failure data Extensive human reliability analysis (HRA) reassessment Revised/updated common cause failure calculations Updated and more detailed ATWS analysis LERF model upgraded to full Level 2 model	1.05×10^{-5}

Engineers (ASME) PRA Standard (ASME 2003) and Regulatory Guide (RG) 1.200 (NRC 2004a), identified a number of items for updating. Changes required to meet Capability Category II of the ASME Standard were then incorporated into the 2004A model. Subsequently, the 2004A model was completely reassessed against the same requirements. AmerGen indicated that most of the “gaps” relative to the requirements have been addressed as part of the current update (i.e., the 2004B update), and that none of the remaining items are judged to affect the SAMA evaluation.

The NRC staff concludes that the Level 1 PRA model is of sufficient quality to support the SAMA evaluation because (1) the OCNGS Level 1 internal events PRA model has been both peer reviewed and subjected to an extensive self-assessment process; (2) the review findings have been resolved or judged to have no adverse impact on the SAMA evaluation; and (3) AmerGen has satisfactorily addressed NRC staff questions regarding the PRA.

1 As indicated above, the current OCNGS PRA (2004B) does not include external events. In the
2 absence of such an analysis, AmerGen used the OCNGS IPEEE to identify the highest risk
3 accident sequences and potential means of reducing the risk posed by those sequences. In
4 addition, subsequent to the ER submittal, a FPRA has been completed. In response to
5 NRC staff RAIs (NRC 2005, 2006), AmerGen described the use of the IPEEE and updated fire
6 analyses to support the identification and evaluation of potential SAMAs related to external
7 events (AmerGen 2006a,b).

8
9 The OCNGS IPEEE was submitted in December 1995, in response to Supplement 4 of
10 GL 88-20 (GPU 1995). GPU Nuclear, Inc., did not identify any fundamental weaknesses or
11 vulnerabilities to severe accident risk in regard to the external events related to seismic, fire, or
12 other external events. In a letter dated February 8, 2001, the NRC staff concluded that the
13 submittal met the intent of Supplement 4 to GL 88-20, and that the licensee's IPEEE process is
14 capable of identifying the most likely severe accidents and severe accident vulnerabilities
15 (NRC 2001).

16
17 The seismic PRA performed for the initial OCNGS IPEEE submittal resulted in a seismic CDF
18 of 3.6×10^{-6} per year. The seismic model was modified significantly as a result of the NRC
19 IPEEE review and subsequently yielded a total seismic CDF of 4.7×10^{-6} per year. The
20 dominant contributors to this value are failure of the turbine building and the reactor building
21 since their failures lead directly to core damage. The seismic IPEEE assumed that all relays
22 that did not meet USI A-46 requirements would be replaced. The NRC staff Safety Evaluation
23 Report (SER) for USI A-46 (NRC 2000) accepted the A-46 resolution. In response to an RAI,
24 AmerGen confirmed that all relays that did not meet A-46 requirements have been replaced or
25 otherwise shown to be acceptable (AmerGen 2006a).

26
27 The OCNGS IPEEE fire analysis consisted of a FPRA based on Electric Power Research
28 Institute's (EPRI's) Fire Induced Vulnerability Evaluation (FIVE) methodology (supplemented by
29 an existing fire hazards analysis) and the IPE internal events PRA models. An initial qualitative
30 screening phase was utilized to screen out fire areas based on a lack of risk-significant
31 components or lack of a demand for a reactor trip. Quantitative screening of fire areas was
32 then employed to screen out areas where the conservatively determined (neglecting fire
33 suppression and conservatively estimating fire propagation) CDF is less than 1×10^{-6} per year.
34 This was then followed by a detailed analysis that included the consideration of fire
35 suppression, fire propagation, and fire severity factor. Eight fire areas required detailed
36 analysis.

37
38 Based on the IPEEE, Table G-4 gives the fire areas with frequencies greater than 1×10^{-6} per
39 year that were considered to be the dominant contributors, comprising more than 80 percent of
40 the estimated total fire CDF.
41

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Table G-4. Significant Fire Areas for OCNGS

Fire Area	Description	CDF (per year)
OB-FZ-4	Lower cable spreading room	8.6×10^{-6}
OB-FZ-6A	480-VAC switchgear room	5.1×10^{-6}
TB-FZ-11D	Turbine building basement	1.9×10^{-6}

The resulting total fire CDF from the IPEEE was estimated as 1.9×10^{-5} per year (NRC 2001).

Subsequent to the ER submittal, AmerGen completed a FPRA for OCNGS (AmerGen 2006a). The FPRA includes a comprehensive reanalysis of the entire plant and indicates a fire CDF of 9.4×10^{-6} per year. AmerGen stated that the reanalysis applied accepted industry methods (as documented in the EPRI Fire PRA Implementation Guide and modified by NRC generic RAIs and responses) and incorporated updated fire frequency values and fire-induced spurious actuation probabilities (AmerGen 2006b). A comparison of the results from the FPRA with those from the IPEEE was provided in response to RAIs (AmerGen 2006a,b) and is summarized below. Included are the dominant contributors to the IPEEE, as listed above, and the areas from the FPRA that have a CDF contribution of more than approximately 2.7×10^{-7} per year (which corresponds to an averted cost risk of approximately \$50,000). The major reason for the reduction in fire CDF is stated to be attributable to the more detailed treatment of fire ignition sources and incorporation of alternate mitigation measures involving the remote shutdown panel for fire area OB-FZ-4.

As Table G-5 indicates, the overall fire CDF from the IPEEE is conservative.

The IPEEE analysis of other external events (GPU 1995) followed the screening specified in Supplement 4 to GL 88-20 (NRC 1991) and did not identify any unduly significant sequences or vulnerabilities. The plant design was reviewed to determine if it met 1975 Standard Review Plan design criteria for high winds, floods, and other external events. If it met these criteria and a walkdown did not identify any unique vulnerabilities, then the CDF from the external hazard was considered to be less than 1×10^{-6} per year. If it did not meet the criteria, then additional analysis was performed to evaluate the specific concern. Since tornadoes were not part of the design basis for OCNGS, high winds and tornadoes could not be screened out. Further analysis summarized in the IPEEE SER (NRC 2001) indicated that the CDF due to high winds and tornadoes is less than 1×10^{-6} per year.

Based on the IPEEE results, the external events CDF (fire: 1.9×10^{-5} per year, seismic: 4.7×10^{-6} per year) is approximately 2.3 times the internal events CDF (1.05×10^{-5} per year). AmerGen argued that, in addition to the fire risk being conservatively estimated, a SAMA derived to address the internal events risk profile will have a less profound impact on the

Table G-5. Comparison of FRPA and IPEEE Core Damage Frequencies

Fire Area	Description	CDF (per year)	
		IPEEE	FPRA
OB-FZ-6A	"A" 480-VAC switchgear room	5.1×10^{-6}	3.1×10^{-6}
OB-FZ-8C	A and B batt room, tunnel and elec tray room	4.6×10^{-7}	2.1×10^{-6}
TB-FZ-11E	Condenser bay	Screened	6.0×10^{-7}
TB-FA-3A	4169-VAC switchgear 1C vault	Screened	5.1×10^{-7}
OB-FZ-5	Control room	3.3×10^{-7}	4.3×10^{-7}
MT-FA-12	Main transformer and condensate storage tank	Screened	3.9×10^{-7}
OB-FZ-4	Cable spreading room	8.6×10^{-6}	3.9×10^{-7}
OB-FZ-10A	Monitoring and change room	Screened	3.8×10^{-7}
TB-FA-3B	4169-VAC switchgear 1D Vault	Screened	3.3×10^{-7}
TB-FZ-11D	Turbine building basement, south end	1.9×10^{-6}	6.2×10^{-8}

external event risk profile, and that assuming a one-to-one correspondence will overestimate the external events benefit. Therefore, in the ER, AmerGen doubled the benefit that was derived from the internal events model to account for the contribution from external events. This doubling was not applied to those SAMAs that specifically addressed external events risk (i.e., SAMAs 67, 124, 125, 130, and 134). Doubling the benefit for these SAMAs is not appropriate since these SAMAs are specific to external event risks and would not have a corresponding benefit on the risk from internal events.

As discussed above, in response to staff RAIs, AmerGen provided the results of an updated FPRA (AmerGen 2006b). The CDF from the FPRA, combined with the IPEEE seismic CDF, yields a total external events CDF of 1.41×10^{-5} per year or approximately 1.3 times the internal events CDF. The total CDF is approximately 2.3 times the CDF internal events. In the discussion provided in the response to RAIs, AmerGen argues that since seismic risk is only marginally impacted by SAMAs intended to mitigate the risk from internal events, the seismic risk should not be included in the total mitigated risk. If seismic is not included, the external events CDF for the purposes of SAMA evaluations is approximately 0.9 times the internal events CDF, or the total CDF is approximately 1.9 times the internal events CDF.

On the basis of the above, the NRC staff concludes that the applicant's use of a multiplier of 2 to account for external events is reasonable for the purposes of the SAMA evaluation.

The NRC staff reviewed the general process used by AmerGen to translate the results of the Level 1 PRA into containment releases, as well as the results of this Level 2 analysis. AmerGen characterized the releases for the spectrum of possible radionuclide release

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scenarios by using a set of release categories defined based on the timing and magnitude of the release. The frequency of each release category was obtained from the quantification of a linked Level 1/Level 2 model that effectively evaluates a containment event tree for each Level 1 accident sequence. The process for assigning accident sequences to the various release categories and the dominant accident sequences for each release category is described in the ER (AmerGen 2005). The release categories were then reduced to 10 consequence categories by combining several of the low and very low release categories. The fission product release fractions for each consequence category were obtained from the results of analyses of representative sequences for each category by using version 4.0.5 of MAAP. The frequencies and fission product release characteristics for each of the release and consequence categories are presented in Tables F-6, F-6a, and F-7 of the ER (AmerGen 2005).

While the IPE Level 2 analysis was reviewed by the NRC and found to be consistent with the intent of the IPE program (NRC 1994), the current Level 2 analysis is a significant modification of the earlier analysis. In response to RAIs, AmerGen described the development of the current model, the reviews performed, and the experience and qualifications of the team that prepared it. The IPE Level 2 model was upgraded in 2003 to a "LERF only" model. This model was included within the PRA self-assessment performed in 2004. The results of this self-assessment against the requirements of the ASME PRA Standard and RG 1.200 were then used to upgrade the 2003 model, while at the same time expanding the scope of the model to treat the spectrum of radionuclide releases. The upgraded Level 2 model was incorporated into the 2004A PRA model and then reassessed against the above requirements. The NRC staff notes that the team that developed the Level 2 model has considerable experience in Level 2 PRA analysis and has been involved in developing industry standards for such analyses. The staff concludes that the process used for determining the consequence category frequencies and source terms is reasonable and appropriate for the purposes of the SAMA analysis.

As indicated in the ER, the reactor core radionuclide inventory used in the consequence analysis is based on a plant-specific ORIGEN 2.1 calculation and corresponds to best estimate, end-of-cycle values for a 24-month fuel cycle. All releases were modeled as occurring at ground level with a thermal content the same as ambient. AmerGen assessed the impact of alternative assumptions (i.e., elevated releases for selected consequence categories). The results of this sensitivity study showed that the 50-mi population dose and offsite economic risks would increase by less than 1 percent.

The NRC staff reviewed the process used by AmerGen to extend the containment performance (Level 2) portion of the PRA to an assessment of offsite consequences (essentially a Level 3 PRA). This included consideration of the major input assumptions used in the offsite consequence analyses. The MACCS2 code was utilized to estimate offsite consequences. Plant-specific inputs to the code include the source terms for each consequence category and

1 the reactor core radionuclide inventory (both discussed above), site-specific meteorological
2 data, projected population distribution within a 50-mi radius for the year 2029, emergency
3 evacuation modeling, and economic data. This information is provided in Appendix F of the ER
4 (AmerGen 2005).

5
6 AmerGen used site-specific meteorological data processed from hourly measurements for the
7 2003 calendar year as input to the MACCS2 code. The hourly data were collected from the
8 onsite meteorological tower. Small data voids (less than six consecutive hours) were filled
9 using interpolation between data points. Larger data voids were filled using data from the
10 previous hours or days. Data from 2000 and 2001 were also considered, but 2003 data were
11 found to be the most complete and resulted in the highest population dose risk and offsite
12 economic cost risk. Data for 2003 were subsequently used in base case MACCS2 risk
13 calculations. (Data for 2002 were not readily available because of modifications to the
14 collection system implemented in mid-2002.) The NRC staff considers use of the 2003
15 meteorological data in the SAMA analysis to be reasonable.

16
17 The population distribution the applicant used as input to the MACCS2 analysis was estimated
18 for the year 2029, using SECPOP2000 (NRC 2003), U.S. Census block-group level population
19 data (USCB 2000), and population growth rate estimates. The 1990 and 2000 census data
20 were used to estimate an annual average population growth rate for each of the 50-mi-radius
21 rings. The annual growth rate estimate for each ring was applied uniformly to all sectors in the
22 respective ring. The NRC staff considers the methods and assumptions for estimating
23 population reasonable and acceptable for purposes of the SAMA evaluation.

24
25 The emergency evacuation model was modeled as a single evacuation zone extending out
26 10 mi from the plant. It was assumed that 95 percent of the population would move at an
27 average speed of approximately 1.3 mph, with a delayed start time of 30 minutes after a
28 General Emergency has been declared (AmerGen 2005). This assumption is conservative
29 relative to the NUREG-1150 study (NRC 1990) that assumed evacuation of 99.5 percent of the
30 population within the emergency planning zone. The evacuation assumptions and analysis are
31 deemed reasonable and acceptable for the purposes of the SAMA evaluation.

32
33 Much of the site-specific economic data were provided from SECPOP2000 (NRC 2003) by
34 specifying the data for each of the counties surrounding the plant, to a distance of 50 mi.
35 Generic economic data were revised from the MACCS2 sample problem when better
36 information was available (e.g., per diem living expenses, relocation costs, and value of farm
37 and nonfarm wealth). These values were updated to the year 2000 by using the Consumer
38 Price Index ratio.

39
40 The NRC staff concludes that the methodology AmerGen used to estimate the offsite
41 consequences for OCNBS provides an acceptable basis from which to proceed with an

assessment of risk reduction potential for candidate SAMAs. Accordingly, the staff based its assessment of offsite risk on the CDF and offsite doses reported by AmerGen.

G.3 Potential Plant Improvements

The process for identifying potential plant improvements, an evaluation of that process, and the improvements evaluated in detail by AmerGen are discussed in this section.

G.3.1 Process for Identifying Potential Plant Improvements

AmerGen's process for identifying potential plant improvements (SAMAs) consisted of the following elements:

- Review of the most significant basic events from the OCNGS 2004B Level 1 and 2 PRA,
- Review of Phase II SAMAs from license renewal applications for five other U.S. nuclear sites,
- Review of potential plant improvements identified in the OCNGS IPE and IPEEE,
- Review of dominant fire areas and SAMAs that could potentially reduce the associated fire risk, and
- Input from OCNGS system managers during the PRA update process and the development of the SAMA list.

On the basis of this process, an initial set of 136 candidate SAMAs was identified. (The ER states that 138 SAMAs were identified; however, two were listed as Not Used.) In Phase I of the evaluation, AmerGen performed a qualitative screening of the initial list of SAMAs and eliminated SAMAs from further consideration using the following criteria:

- The SAMA is not applicable at OCNGS because of design differences;
- The SAMA requires extensive changes that would involve implementation costs known to exceed any possible benefit (a screening value of \$4.46 million, which represents the dollar value associated with completely eliminating all internal and external event severe accident risk at OCNGS, was used to support this determination);
- The SAMA has already been implemented at OCNGS;

- The implementation cost obviously exceeds the benefit, or the benefit is negligible; or
- The SAMA has been addressed by a similar SAMA.

Based on this screening, 99 SAMAs were eliminated, leaving 37 for further evaluation. The remaining SAMAs are listed in Table F-16 of the ER (AmerGen 2005). A detailed evaluation was performed for each of the 37 remaining SAMA candidates, as described in Sections G.4 and G.6 below. To account for the potential impact of external events, the estimated benefits based on internal events were multiplied by a factor of 2 (except for those SAMAs specific to external events, since those SAMAs would not have a corresponding benefit on the risk from internal events).

G.3.2 Review of AmerGen's Process

AmerGen's efforts to identify potential SAMAs focused primarily on areas associated with internal initiating events, but also included explicit consideration of potential SAMAs for seismic, fire, and high wind events. The initial list of SAMAs generally addressed the accident sequences considered to be important to CDF from functional, initiating event, and risk reduction worth (RRW) perspectives at OCNGS, and included selected SAMAs from other plants.

AmerGen provided a tabular listing of the PRA basic events sorted according to their RRW (AmerGen 2005). SAMAs impacting these basic events would have the greatest potential for reducing risk. AmerGen used a RRW cutoff of 1.01, which approximately corresponds to a 1 percent change in CDF given 100 percent reliability of the event. This equates to an averted cost risk (benefit) of approximately \$45,000 (after the benefits are doubled to account for external events). AmerGen also provided and reviewed the LERF-based RRW events down to an RRW of 1.01. AmerGen correlated the top Level 1 and 2 events with the SAMAs evaluated in the ER and showed that all of the significant basic events are addressed by one or more SAMAs (AmerGen 2005). Based on this information, the NRC staff concludes that the set of SAMAs evaluated in the ER addresses the major contributors to CDF and offsite dose.

Although the IPE did not identify any vulnerabilities, 15 modifications to the plant, procedures, and training were identified that had either been implemented, were to be implemented, or were being considered at the time of the completion of the IPE process. Eight of the improvements have not been completed and were included as candidate SAMAs in the current evaluation.

AmerGen identified OCNGS-specific candidate SAMAs for external events by using the OCNGS IPEEE (as well as the recently completed FPRA.) A total of 14 SAMAs were identified to address external events and were included as candidate SAMAs in the Phase I analysis. These included 11 seismic-related SAMAs and 3 fire-related SAMAs. In addition, two SAMAs

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related to high wind events were identified and included based on input from OCNGS system managers. Of these SAMAs, five were retained for more detailed evaluation in the Phase II analysis, specifically, two seismic-related SAMAs (67 and 124), one fire-related SAMA (125), and two high-wind-related SAMAs (130 and 134).

The NRC staff notes that the set of SAMAs submitted is not all inclusive, since additional, possibly even less expensive, design alternatives can always be postulated. However, the staff concludes that the benefits of any additional modifications are unlikely to exceed the benefits of the modifications evaluated and that the alternative improvements would not likely cost less than the least expensive alternatives evaluated, when the subsidiary costs associated with maintenance, procedures, and training are considered.

The NRC staff concludes that AmerGen used a systematic and comprehensive process for identifying potential plant improvements for OCNGS, and that the set of potential plant improvements identified by AmerGen is reasonably comprehensive and therefore acceptable. This search included reviewing insights from the plant-specific risk studies, reviewing plant improvements considered in previous SAMA analyses, and using the knowledge and experience of its PRA personnel.

G.4 Risk Reduction Potential of Plant Improvements

AmerGen evaluated the risk reduction potential of the 37 remaining SAMAs that were applicable to OCNGS. The changes made to the model to quantify the impact of the SAMAs are detailed in Section F.6 of Appendix F to the ER (AmerGen 2005). The SAMA evaluations were performed by using realistic assumptions with some conservatism.

AmerGen used model requantification to determine the potential benefits. The CDF and population dose reductions were estimated by using the 2004B model version of the OCNGS PRA. Table G-6 lists the assumptions considered to estimate the risk reduction for each of the evaluated SAMAs, the estimated risk reduction in terms of percent reduction in CDF and population dose, and the estimated total benefit (present value) of the averted risk. The estimated benefits reported in Table G-6 reflect the combined benefit in both internal and external events. The determination of the benefits for the various SAMAs is further discussed in Section G.6.

For those SAMAs that specifically address external events (i.e., SAMAs 67, 124, 125, 130, and 134), the reduction in CDF and population dose were calculated as discussed below.

SAMAs 67 and 124 involve modifying the condensate storage tank and reinforcing a block wall to increase their capability in seismic events. For these SAMAs, a seismic baseline risk (CDF,

Table G-6. SAMA Cost-Benefit Screening Analysis for OCNGS

SAMA ^(a)	Assumptions	% Risk Reduction		Total Benefit Using 7% Discount Rate (\$)	Total Benefit Using 3% Discount Rate (\$)	Cost (\$)
		CDF	Population Dose			
7. Enhance alternate injection reliability. Provide hard pipe cross-connection between emergency service water (ESW) and core spray.	Failure probability of 1×10^{-2} assigned to represent operator action and additional equipment operation that could prevent the modification from functioning.	3	4	174,000	240,000	500,000
10. Install alternate path to the torus hard pipe vent via the wet well using a rupture disk.	Operator actions and AC and DC power associated with venting removed from model.	16	19	788,000	1,088,000	1,000,000
18. Improve ability to cool residual heat removal (RHR) heat exchangers through procedure and hardware modifications to allow manual alignment of the fire protection system.	Change model logic such that failure of service water AND failure of fire water, in addition to ESW pumps required for failure of containment spray heat exchangers.	0.5	0.3	8,000	10,000	265,000
20. Reopen main steam isolation valves (MSIVs) to restore main condenser as a heat sink.	Operator error of 0.1 assumed for reopening of spuriously closed steam line.	0.4	0.3	4,000	6,000	400,000
23. Enable manual bypass of explosive valves via installation of a bypass line and manual valve.	Operator error of 0.01 assumed for use of new bypass valve.	0.7	1	42,000	58,000	150,000

Table G-6. (contd)

SAMA ^(a)	Assumptions	% Risk Reduction		Total Benefit Using 7% Discount Rate (\$)	Total Benefit Using 3% Discount Rate (\$)	Cost (\$)
		CDF	Population Dose			
25. Install bypass switch to enable quick bypassing of low-pressure permissive for core spray.	Operator error of 0.01 assumed for operator action to bypass the permissive.	0.3	0.3	4,000	6,000	50,000
67. Strengthen seismic capability of the condensate storage tank (CST).	Factor of 5 reduction in CST seismic failure contribution to seismic core damage frequency (CDF).	251	251	139,000	190,000	1,000,000
84. Enable manual operation of all containment vent valves via local controls.	Operator error of 0.01 assumed as alternate if support systems fail.	2	2	80,000	110,000	150,000
88. Modify procedure(s) to specify a control band for containment venting.	Reduction by factor of 10 in operator error for failure to control venting.	0.1	0	0	0	50,000
89. Improve procedure(s) for aligning shutdown cooling (SDC) given high dry well pressure	Operator error requantified considering time available to align SDC increased from 3 hours to 19 hours.	~0	~0	0	0	50,000

Table G-6. (contd)

006

		SAMA ^(a)	Assumptions	% Risk Reduction		Total Benefit Using 7% Discount Rate (\$)	Total Benefit Using 3% Discount Rate (\$)	Cost (\$)
				CDF	Population Dose			
1	G-17	91. Modify procedures and training to allow operators to cross-tie emergency AC Buses 1C and 1D under emergency conditions that require operation of critical equipment.	Added gates for divisions of core spray and containment spray that are potentially available with the new cross-tie. Operator error of 0.1 assumed for action to align the new cross-tie.	3	3	118,000	162,000	90,000
2								
3								
4								
5								
6								
7								
8	G-17	92. Modify procedure to eliminate flow restriction and maximize control rod drive (CRD) flow.	Model revised to allow credit for CRD for all events except loss-of-coolant accident (LOCAs).	2	0.6	36,000	50,000	100,000
9								
10								
11	Draft NUREG-1437, Supp	94. Modify Emergency Operating Procedures (EOPs) to provide a crew action to align fire protection for reactor pressure vessel (RPV) injection.	Operator errors associated with aligning fire protection system reevaluated considering 5-minute increase to cognitive time window.	0.2	0	0	0	50,000
12								
13								
14								
15								
16		95. Modify procedure(s) to include a caution that containment spray should not be secured if being utilized for accident mitigation.	No penalty is included in the Probabilistic Risk Assessment (PRA) for associated error of commission, thus no benefit calculated.	~0	~0	0	0	50,000
17								
18								
19								
20								

Table G-6. (contd)

SAMA ^(a)	Assumptions	% Risk Reduction		Total Benefit Using 7% Discount Rate (\$)	Total Benefit Using 3% Discount Rate (\$)	Cost (\$)
		CDF	Population Dose			
99. Modify procedures and training to operate the isolation condensers (ICs) with no support systems available.	Factor of 10 reduction in operator error associated with opening IC when DC power is unavailable.	16	16	674,000	928,000	150,000
100. Modify the circuit to allow the combustion turbines (CTs) to also supply the "A" bus directly.	Added gates for divisions of core spray and containment spray that are potentially available with the new connection. Also a revised model for increased feedwater system availability (0.01) and heat removal paths (0.1).	4	4	146,000	204,000	500,000
101. Provide a procedure for determining RPV level using fuel zone level indicators with standby liquid control operating.	Factor of 3 reduction in operator errors associated with lowering level to control power for an anticipated transient without scram (ATWS).	0.2	0	0	0	50,000
102. Revise AWTs EOP to provide RPV level correction based on power.	Factor of 3 reduction in operator errors associated with lowering level to control power for an ATWS.	0.2	0	0	0	50,000

Table G-6. (contd)

SAMA ^(a)	Assumptions	% Risk Reduction		Total Benefit Using 7% Discount Rate (\$)	Total Benefit Using 3% Discount Rate (\$)	Cost (\$)	
		CDF	Population Dose				
104.	Develop loss of circulating water abnormal operating procedure to include guidance to allow condensate and feedwater to be adequately protected.	Added credit for cooling condensate pumps by service water as a backup to circulating water. No operator actions modeled.	3	0.8	44,000	60,000	250,000
106.	Revise procedure to provide direction for cooldown following loss of reactor building closed cooling water by reducing RPV pressure.	Assumed a 10% reduction in seal LOCA probability.	0.7	0.6	34,000	46,000	50,000
107.	Modify the spill valve air supply to be fitted with air accumulators.	Reduced probability of losing CST inventory on loss of instrument air from 0.1 to 0.001.	0.1	0	0	0	250,000
108.	Relocate reference leg instrument penetration closer to top of active fuel and recalibrate.	Reduced operator errors to adequately control water level while using either condensate pumps or fire protection or core spray systems following an ATWS.	~0	~0	0	0	1,000,000

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Draft NUREG-1437, Supplement 28

Table G-6. (contd)

SAMA ^(a)	Assumptions	% Risk Reduction		Total Benefit Using 7% Discount Rate (\$)	Total Benefit Using 3% Discount Rate (\$)	Cost (\$)
		CDF	Population Dose			
109/125A. Provide portable battery charger capable of supplying 125-V DC buses.	Combined operator error and equipment failure probability of 0.1 in added credit for non-LOCA loss of AC power sequences.	16 ^(b) 54 ^(c)	16 ^(b) 59 ^(c)	674,000 3,390,000	930,000 4,680,000	75,000
110. Delete high dry well pressure signal from shutdown cooling isolation.	Same as SAMA 89.	~0	~0	0	0	75,000
111. Provide alternate dry well spray injection source, e.g., emergency service-water cross-tie, service-water cross-tie, diesel fire pump cross-tie.	Credit given for use of fire protection system in case of failure of each set of containment spray pumps.	~0	~0	0	0	500,000
112. Ensure high reliability of the cooling-water intake structure via surveillance and active programs.	Loss of intake structure initiating event frequency reduced by approximately a factor of 5.	0.8	0.3	8,000	10,000	1,000,000
124. Reinforce block wall 53.	Seismic CDF contribution from block wall failure eliminated. Release parameters based on modified Individual Plant Examination of External Events (IPEEE) seismic Class distribution.	15 ^d	151 ^d	84,000	115,000	150,000

Table G-6. (contd)

	SAMA ^(a)	Assumptions	% Risk Reduction		Total Benefit Using 7% Discount Rate (\$)	Total Benefit Using 3% Discount Rate (\$)	Cost (\$)
			CDF	Population Dose			
1 2	125B. Add a bus cross-tie circuit breaker to Bus 1B2.	Eliminates fire risk of Area OB-FZ-6A based on Fire Probabilistic Risk Assessment (FPRA) results.	15 ^e	12 ^e	445,000	611,000	100,000
3 4 5 6 7 8 9	125C. Relocation of relief valve cables, circuitry, and components, as well as other modifications, to ensure one train of core spray remains unaffected by fire.	Eliminated dominant contributors to fire risk remaining after implementation of SAMAs 109/125A and 125B.	29 ^f	17 ^f	397,000	540,000	750,000
10 11 12 13	127. Increase operator training on systems and operator actions determined to be important in the PRA.	Not modeled.	Not estimated	Not estimated			50,000
14 15	128. Institute a program to reduce IC biofouling.	Reduce biofouling basic events by an order of magnitude.	~0	~0	14,000	20,000	200,000
16 17	129. Improve internal flooding procedures.	Reduce all internal flood initiating events except "Fire Protection Spray of Buses 1A, 1B" by a factor of 2.	4	1	56,000	78,000	100,000

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Draft NUREG-1437, Supplement 28

Table G-6. (contd)

SAMA ^(a)	Assumptions	% Risk Reduction		Total Benefit Using 7% Discount Rate (\$)	Total Benefit Using 3% Discount Rate (\$)	Cost (\$)
		CDF	Population Dose			
130. Increase CT building integrity to withstand higher winds.	Assumed factor of 20 reduction in extreme weather loss of offsite power (LOOP), which also causes failure of CT.	30	34	747,000	1,032,000	600,000
132. Modify procedures to allow switching of the CTs to OCNGS while running.	Probability of spurious trip of running CT assumed to be 0.5.	1	1	46,000	64,000	50,000
133. Increase the hot well makeup capability to allow condensate/feedwater to be beneficial over a wide range of LOCA conditions.	Remove from model failure of feedwater due to insufficient makeup capability.	1	2	72,000	100,000	250,000
134. Increase fire pump building integrity to withstand higher winds.	Assumed factor of 20 reduction in extreme weather LOOP, which also causes failure of fire pump building.	16	19	438,000	606,000	150,000
136. Provide alternate power to condensate transfer pumps.	Add gates for alternate AC power supplies to individual condensate transfer pump models.	0.2	0	0	0	100,000

Table G-6. (contd)

SAMA ^(a)	Assumptions	% Risk Reduction		Total Benefit Using 7% Discount Rate (\$)	Total Benefit Using 3% Discount Rate (\$)	Cost (\$)
		CDF	Population Dose			
138. Protect transformers from explosive failure.	LOOP frequency increased by 1×10^{-2} per year to incorporate impact of postulated transformer explosions.	8 ^(g)	9 ^(g)	446,000	616,000	780,000

(a) SAMAs in bold are potentially cost-beneficial when either a 7 percent or 3 percent real discount rate is used in the NRC staff's analysis.

(b) Value based on doubling of internal events benefits, as reported in ER Section F.6.23 (AmerGen 2005) for SAMA 109.

(c) Value based on modified base PRA that incorporates the dominant fire risk contributors from the FPRA update, as reported in ER Section F.6.28 for SAMA 125A.

(d) Values represent the reduction in seismic risk. Risk from internal and fire events is assumed to be unchanged.

(e) Value based on updated FPRA results, as described in AmerGen's response to RAI followup questions (AmerGen 2006b).

(f) Benefit is based on prior implementation of SAMAs 109/125A and 125B.

(g) Impact of transformer explosion not in current PRA. Risk reduction of SAMA is, therefore, equal to risk increase when it is added to the model.

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population dose, and offsite economic cost risk) was developed from the IPEEE Level 1 seismic results, and release parameters based on IPEEE seismic accident class distribution, and release characteristics were estimated based on the current Level 2 model. The contribution to seismic CDF from each of the failures addressed by the SAMAs was then estimated from the IPEEE and used with the seismic baseline risk to estimate the averted cost risk. These SAMAs were assumed to have no additional benefits in internal events.

SAMA 125 was subsequently separated into three specific SAMAs that address fire risk contributors: SAMA 125A involves providing portable battery chargers capable of supplying 125-V DC buses, SAMA 125B involves adding a circuit breaker related to fire area OB-FZ-6A, and SAMA 125C involves rerouting of cable in dominant fire areas. To determine the benefit of these modifications, a new baseline risk was determined by incorporating the two dominant fire areas from the FPRA reanalysis into the internal events PRA. The benefits of the SAMA 125 modifications were then determined by making appropriate changes to this new baseline risk model and reevaluating the risk. The evaluations for each SAMA are discussed below.

- SAMA 125A – This SAMA involves providing a portable battery charger capable of supplying 125-V DC buses in order to preserve isolation condenser and electromagnetic relief valve operability along with adequate instrumentation. The same plant change was identified as SAMA 109, based on internal event considerations. SAMA 109 and 125A represent the same physical modification evaluated by using two different approaches. The first approach is based on a doubling of benefits from the internal events PRA to account for external events, and results in an estimated benefit of \$674,000 based on a 7 percent discount rate. The second approach is based on the use of the modified baseline risk model, which incorporates the two dominant fire areas from the FPRA reanalysis, and results in an estimated benefit of \$3.4 million based on a 7 percent discount rate. The latter value is considered the best value to use for the benefit of SAMAs 109/125A.

The NRC staff notes that SAMA 109 was singled out for reevaluation by using the revised fire model because it was designed to deal with station blackout sequences; these types of sequences dominate both the internal event risk and the fire risk. Other internal event SAMAs were reviewed by AmerGen to identify similar circumstances and found not to be applicable, or to be less beneficial than SAMA 109.

- SAMA 125B – This SAMA involves the installation of an additional circuit breaker on Bus 1B2 in order to reduce a failure mode applicable to fires in the “A” 480-VAC switchgear room. The estimated benefit for SAMA 125B reported in the ER is based on an assumption that SAMA 109/125A has already been implemented (i.e., the residual risk after implementing SAMA 109/125A was used as the baseline for determining the further benefit of SAMA 125B.) In response to an RAI, AmerGen provided an estimate

of the benefits associated with SAMA 125B without credit for prior implementation of SAMA 109/125A (AmerGen 2006b). This estimate was based on the result of the FPRA. The averted cost risk for SAMA 125B (without credit for implementation of SAMA 109/125A) is approximately \$445,000, based on a 7 percent discount rate.

- SAMA 125C – This SAMA involves the relocation of relief valve cables, circuitry, and components to allow credit for depressurization and core spray as a backup to the isolation condenser. In addition, other modifications would be required to ensure that at least one train of core spray remains unaffected by the postulated fire event. The risk after incorporation of SAMAs 109/125A and 125B was used as the baseline to evaluate SAMA 125C. The averted cost risk for SAMA 125C (with credit for prior implementation of SAMAs 109/125A and 125B) is approximately \$397,000 based on a 7 percent discount rate. AmerGen did not provide an estimate for the implementation of SAMA 125C alone on the basis that the costs, competing risks, and expected benefit associated with this SAMA would make it undesirable. In a follow-up RAI response, AmerGen indicated that if SAMA 125B is not implemented for fire area OB-FZ-6A, then SAMA 125C should be considered in place of SAMA 125B (AmerGen 2006b).

SAMAs 130 and 134 involve modifications to the combustion turbine building and fire pump building to address high wind events. For these SAMAs, the internal events model includes the impact of failure of the building due to high winds by taking no credit for these components/structures for those Loss of Offsite Power events that are due to extreme winds. The benefit of strengthening these structures to withstand higher wind speeds was estimated by reducing the probability that extreme winds would fail these structures. Since these SAMAs would not have any impact on risk from other external events, the factor of 2 multiplier for external events was not applied. In response to an NRC RAI, AmerGen discussed the implications of changes in the wind hazard curve suggested by an NRC RAI on the IPEEE, and provided additional benefit estimates based on an alternative wind hazard curve. The NRC staff believes that the original assessment of the benefits of SAMAs 130 and 134, as provided in the ER, are appropriate.

The NRC staff has reviewed AmerGen's bases for calculating the risk reduction for the various plant improvements and concludes that the rationale and assumptions for estimating risk reduction are reasonable and somewhat conservative (i.e., the estimated risk reduction is similar to or somewhat higher than what would actually be realized). Accordingly, the staff based its estimates of averted risk for the various SAMAs on AmerGen's risk reduction estimates.

G.5 Cost Impacts of Candidate Plant Improvements

AmerGen estimated the costs of implementing the 37 candidate SAMAs through the application of engineering judgment, use of other licensees' estimates for similar improvements, and development of site-specific cost estimates. The cost estimates conservatively did not include the cost of replacement power during extended outages required to implement the modifications, nor did they include contingency costs associated with unforeseen implementation obstacles. The cost estimates provided in the ER did not account for inflation.

The NRC staff reviewed the bases for the applicant's cost estimates. For certain improvements, the staff also compared the cost estimates with estimates developed elsewhere for similar improvements, including estimates developed as part of other licensees' analyses of SAMAs for operating reactors and advanced light-water reactors. The staff reviewed the costs and found them to be consistent with estimates provided in support of other plants' analyses.

The NRC staff concludes that the cost estimates provided by AmerGen are sufficient and appropriate for use in the SAMA evaluation.

G.6 Cost-Benefit Comparison

AmerGen's cost-benefit analysis and the NRC staff's review are described in the following sections.

G.6.1 AmerGen's Evaluation

The methodology used by AmerGen was based primarily on NRC's guidance for performing cost-benefit analysis, that is, NUREG/BR-0184, *Regulatory Analysis Technical Evaluation Handbook* (NRC 1997b). The guidance involves determining the net value for each SAMA according to the following formula:

$$\text{Net Value} = (\text{APE} + \text{AOC} + \text{AOE} + \text{AOSC}) - \text{COE}$$

where,

- APE = present value of averted public exposure (\$),
- AOC = present value of averted offsite property damage costs (\$),
- AOE = present value of averted occupational exposure costs (\$),
- AOSC = present value of averted onsite costs (\$), and
- COE = cost of enhancement (\$).

If the net value of a SAMA is negative, the cost of implementing the SAMA is larger than the benefit associated with the SAMA and it is not considered cost-beneficial. AmerGen's derivation of each of the associated costs is summarized below.

NUREG/BR-0058 has recently been revised to reflect the agency's policy on discount rates. Revision 4 of NUREG/BR-0058 states that two sets of estimates should be developed: one at 3 percent and one at 7 percent (NRC 2004b). AmerGen provided both sets of estimates (AmerGen 2005).

Averted Public Exposure (APE) Costs

The APE costs were calculated by using the following formula:

$$\begin{aligned} \text{APE} = & \text{Annual reduction in public exposure } (\Delta \text{ person-rem/year}) \\ & \times \text{monetary equivalent of unit dose } (\$2000 \text{ per person-rem}) \\ & \times \text{present value conversion factor } (10.76 \text{ based on a 20-year period with a} \\ & \quad 7 \text{ percent discount rate}). \end{aligned}$$

As stated in NUREG/BR-0184 (NRC 1997b), it is important to note that the monetary value of the public health risk after discounting does not represent the expected reduction in public health risk due to a single accident. Rather, it is the present value of a stream of potential losses extending over the remaining lifetime (in this case, the renewal period) of the facility. Thus, it reflects the expected annual loss due to a single accident, the possibility that such an accident could occur at any time over the renewal period, and the effect of discounting these potential future losses to present value. For the purposes of initial screening, which assumes elimination of all severe accidents due to internal events, AmerGen calculated an APE of approximately \$775,000 for the 20-year license renewal period.

Averted Offsite Property Damage Costs (AOC)

The AOCs were calculated by using the following formula:

$$\begin{aligned} \text{AOC} = & \text{Annual CDF reduction} \\ & \times \text{offsite economic costs associated with a severe accident (on a per-event} \\ & \quad \text{basis)} \\ & \times \text{present value conversion factor.} \end{aligned}$$

For the purposes of initial screening, which assumes all severe accidents due to internal events are eliminated, AmerGen calculated an annual offsite economic risk of about \$118,000 based on the Level 3 risk analysis. This results in a discounted value of approximately \$1,270,000 for the 20-year license renewal period.

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Averted Occupational Exposure (AOE) Costs

The AOE costs were calculated by using the following formula:

$$\begin{aligned} \text{AOE} = & \text{Annual CDF reduction} \\ & \times \text{occupational exposure per core damage event} \\ & \times \text{monetary equivalent of unit dose} \\ & \times \text{present value conversion factor.} \end{aligned}$$

AmerGen derived the values for averted occupational exposure from information provided in Section 5.7.3 of the regulatory analysis handbook (NRC 1997b). Best estimate values provided for immediate occupational dose (3300 person-rem) and long-term occupational dose (20,000 person-rem over a 10-year cleanup period) were used. The present value of these doses was calculated by using the equations provided in the handbook in conjunction with a monetary equivalent of unit dose of \$2000 per person-rem, a real discount rate of 7 percent, and a time period of 20 years to represent the license renewal period. For the purposes of initial screening, which assumes all severe accidents due to internal events are eliminated, AmerGen calculated an AOE of approximately \$4000 for the 20-year license renewal period.

Averted Onsite Costs (AOSC)

The AOSC include averted cleanup and decontamination costs and averted power replacement costs. Repair and refurbishment costs are considered for recoverable accidents only and not for severe accidents. AmerGen derived the values for AOSC based on information provided in Section 5.7.6 of the regulatory analysis handbook (NRC 1997b).

AmerGen divided this cost element into two parts: the Onsite Cleanup and Decontamination Cost, also commonly referred to as averted cleanup and decontamination costs, and the Replacement Power Cost.

Averted cleanup and decontamination costs (ACC) were calculated by using the following formula:

$$\begin{aligned} \text{ACC} = & \text{Annual CDF reduction} \\ & \times \text{present value of cleanup costs per core damage event} \\ & \times \text{present value conversion factor.} \end{aligned}$$

The total cost of cleanup and decontamination subsequent to a severe accident is estimated in the regulatory analysis handbook to be $\$1.1 \times 10^9$ (discounted). This value was converted to present costs over a 10-year cleanup period and integrated over the term of the proposed license extension. For the purposes of initial screening, which assumes all severe accidents

1 due to internal events are eliminated, AmerGen calculated an ACC of approximately \$124,000
 2 for the 20-year license renewal period.

3
 4 Long-term replacement power costs (RPC) were calculated using the following formula:

$$\begin{aligned}
 \text{RPC} = & \text{Annual CDF reduction} \\
 & \times \text{present value of replacement power for a single event} \\
 & \times \text{factor to account for remaining service years for which replacement power is} \\
 & \text{required} \\
 & \times \text{reactor power scaling factor}
 \end{aligned}$$

11
 12 AmerGen based its calculations on the value of 630 megawatts electric (MW[e]). Therefore,
 13 AmerGen applied power scaling factors of 630 MWe/910 MWe to determine the replacement
 14 power costs. For the purposes of initial screening, which assumes all severe accidents due to
 15 internal events are eliminated, AmerGen calculated the AOSC to be approximately \$182,000.

16
 17 By using the above equations, AmerGen estimated the total present dollar value equivalent
 18 associated with completely eliminating severe accidents due to internal events at OCNCS to be
 19 about \$2,231,000. To account for additional risk reduction in external events, AmerGen
 20 doubled this value (to \$4,462,000) to provide the modified maximum averted cost risk
 21 (MMACR), which represents the dollar value associated with completely eliminating all internal
 22 and external event severe accident risk at OCNCS.

23 24 AmerGen's Results

25
 26 If the implementation costs for a candidate SAMA were greater than the MMACR of
 27 \$4,462,000, then the SAMA was screened from further consideration. A more refined look at
 28 the costs and benefits was performed for the remaining SAMAs. If the implementation costs for
 29 a candidate SAMA exceeded the calculated benefit, the SAMA was considered not to be cost-
 30 beneficial. In the baseline analysis contained in the ER (using a 7 percent discount rate),
 31 AmerGen identified seven potentially cost-beneficial SAMAs. On the basis of an analysis using
 32 a 3 percent real discount rate, as recommended in NUREG/BR-0058 (NRC 2004b), two
 33 additional SAMA candidates were determined to be potentially cost-beneficial. The potentially
 34 cost-beneficial SAMAs are:

- 35
 36 • SAMA 10 – install alternate path to the torus hard pipe vent via the wet well using a
 37 rupture disk (cost-beneficial at 3 percent discount rate),
- 38
 39 • SAMA 91 – modify procedures and training to allow operators to cross-tie emergency
 40 AC Buses 1C and 1D under emergency conditions that require operation of critical
 41 equipment,

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- SAMA 99 – modify procedures and training to operate the isolation condensers with no support systems available,
- SAMA 109/125A – provide portable DC battery charger capable of supplying 125-V buses in order to preserve isolation condenser and electromagnetic relief valve operability along with adequate instrumentation,
- SAMA 125B – add a bus cross-tie circuit breaker to Bus 1B2 to reduce the impact of fires in the 480-V AC switchgear room,
- SAMA 127 – increase operator training on the systems and operator actions determined to be important from the PRA,
- SAMA 130 – increase combustion turbine building integrity to withstand higher winds so that combustion turbines would be capable of withstanding a severe weather event,
- SAMA 132 – modify procedures to allow switching of the combustion turbines to OCNCS while running (cost-beneficial at 3 percent discount rate), and
- SAMA 134 – increase fire pump house building integrity to withstand higher winds so that the fire system would be capable of withstanding a severe weather event.

AmerGen performed additional analyses to evaluate the impact of parameter choices and uncertainties on the results of the SAMA assessment (AmerGen 2005). If the benefits are increased by a factor of 2.5 to account for uncertainties, six additional SAMA candidates (beyond those identified in the 3 percent discount rate case) were determined to be potentially cost-beneficial (SAMAs 84, 106, 124, 125C, 129, and 138). The potentially cost-beneficial SAMAs are discussed in more detail in Section G.6.2.

G.6.2 Review of AmerGen's Cost-Benefit Evaluation

The cost-benefit analysis performed by AmerGen was based primarily on NUREG/BR-0184 (NRC 1997b) and was executed consistent with this guidance.

To account for external events, AmerGen multiplied the internal event benefits by a factor of 2 for each SAMA, except those SAMAs that specifically address external events (i.e., SAMAs 67, 124, 125, 130, and 134). Doubling the benefit for these SAMAs is not appropriate since these SAMAs are specific to external events and would not have a corresponding benefit in risk from internal events. Given that the CDF from internal fires and other external events as reported by AmerGen is less than the CDF for internal events, the NRC staff agrees that the factor of 2 multiplier for external events is reasonable.

AmerGen considered the impact that possible increases in benefits from analysis uncertainties would have on the results of the SAMA assessment. Currently, an uncertainty distribution is not available for the SAMA PRA model. Therefore, AmerGen reviewed the point estimate and 95th percentile CDFs for several SAMA submittals. The factor by which the 95th percentile CDFs are greater than the point estimate CDFs ranged from 2.35 to 2.45 (AmerGen 2005). AmerGen reexamined the initial set of SAMAs to determine if any additional Phase I SAMAs would be retained for further analysis if the benefits were increased by a factor of 2.5. No additional Phase I SAMAs were identified. AmerGen also considered the impact on the Phase II screening if the benefits were increased by a factor of 2.5 (in addition to the factor of 2 multiplier already included in the baseline benefit estimates to account for external events). Six additional SAMAs (beyond the nine SAMAs identified above) could be cost-beneficial. These additional SAMAs are SAMAs 84, 106, 124, 125C, 129, and 138.

AmerGen recognized that a combination of lower-cost SAMAs can provide much of the risk reduction associated with higher-cost SAMAs, and may act synergistically to yield a combined risk reduction greater than the sum of the benefits for each SAMA if implemented individually. AmerGen assessed various combinations of the seven potentially cost-beneficial SAMAs identified in the baseline case. Based on this, AmerGen identified a subset of four SAMAs along with a priority for implementation based on individual maximum net values. In order of implementation priority, they are:

- SAMA 109/125A – provide portable DC battery charger capable of supplying 125-V buses in order to preserve isolation condenser and electromagnetic relief valve operability along with adequate instrumentation,
- SAMA 134 – increase fire pump house building integrity to withstand higher winds so that the fire system would be capable of withstanding a severe weather event,
- SAMA 125B – add a bus cross-tie circuit breaker to Bus 1B2 to reduce the impact of fires in the 480-V AC switchgear room, and
- SAMA 127 – increase operator training on the systems and operator actions determined to be important from the PRA.

AmerGen concluded that if the above SAMAs are implemented, then the remaining SAMAs identified as cost-beneficial in the baseline analysis (i.e., SAMAs 91, 99, and 130) will no longer be cost-beneficial (AmerGen 2005).

The NRC staff noted that several SAMAs, which are only cost-beneficial at the upper bound (95th percentile), do not appear to have competing effects and may remain cost-beneficial (at the upper bound) even after implementing the four aforementioned SAMAs. Therefore, the

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staff asked AmerGen to provide an assessment of the upper bound net values for these SAMAs (i.e., SAMAs 10, 84, 106, 124, 125C, 129, 132, and 138), assuming that the four cost-beneficial SAMAs noted above are implemented (NRC 2005). In its response, AmerGen provided the upper bound net values for these SAMAs (AmerGen 2006a). With the exception of SAMAs 84 and 138, these SAMAs remained individually cost-beneficial at the upper bound. Two of these SAMAs (10 and 125C) have large implementation costs (approximately \$1 million); however, the upper bound net values are also large (approximately \$200,000 to \$800,000). The other four SAMAs (99, 129, 132, and 124) have lower implementation costs (\$50,000 to \$150,000), but also have lower net values (\$60,000 to \$90,000).

The NRC staff concludes that, with the exception of the potentially cost-beneficial SAMAs discussed above, the costs of the SAMAs evaluated would be higher than the associated benefits.

G.7 Conclusions

AmerGen compiled a list of 136 SAMAs based on a review of the most significant basic events from the plant-specific PRA, Phase II SAMAs from license renewal activities for other plants, insights from the plant-specific IPE and IPEEE, review of dominant fire areas, and input from OCNGS systems managers. A qualitative screening removed SAMA candidates that (1) were not applicable at OCNGS because of design differences, (2) required extensive changes that would involve implementation costs known to exceed any possible benefit (i.e., more than \$4.46 million), (3) had already been implemented at OCNGS, (4) had a negligible benefit, or (5) had been addressed by a similar SAMA. Ninety-nine SAMAs were eliminated, leaving 37 for further evaluation.

For the remaining SAMA candidates, a more detailed design and cost estimates were developed as shown in Table G-6. The cost-benefit analyses showed that seven of the SAMA candidates were potentially cost-beneficial in the baseline analysis. AmerGen performed additional analyses to evaluate the impact of parameter choices and uncertainties on the results of the SAMA assessment. As a result, seven additional SAMAs were identified as potentially cost-beneficial. AmerGen evaluated the impact of implementing four potentially cost-beneficial SAMAs. The evaluation indicated that the remaining three SAMAs that were determined to be cost-beneficial in the baseline analysis would no longer be cost-beneficial. However, several SAMAs would remain potentially cost-beneficial when evaluated at the upper bound.

The NRC staff reviewed the AmerGen analysis and concluded that the methods used and the implementation of those methods were sound. The treatment of SAMA benefits and costs support the general conclusion that the SAMA evaluations performed by AmerGen are reasonable and sufficient for the license renewal submittal. Although the treatment of SAMAs for external events was somewhat limited by the unavailability of an external events PRA, the

likelihood of there being cost-beneficial enhancements in this area was minimized by inclusion of several candidate SAMAs related to external events, insights from the FPRA, and inclusion of a multiplier to account for external events.

The NRC staff concurs with AmerGen's identification of areas in which risk can be further reduced in a cost-beneficial manner through the implementation of all or a subset of the identified, potentially cost-beneficial SAMAs. Given the potential for cost-beneficial risk reduction, the staff concludes that further evaluation of these SAMAs by AmerGen is warranted. However, none of these SAMAs relate to adequately managing the effects of aging during the period of extended operation. Therefore, they need not be implemented as part of license renewal pursuant to 10 CFR Part 54.

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10. SUPPLEMENTARY NOTES

Docket No. 50-219

11. ABSTRACT (200 words or less)

This Supplement Environmental Impact Statement (SEIS) has been prepared in response to an application submitted to the NRC by AmerGen Energy Company, LLC, to renew the Operating License for Oyster Creek Nuclear Generating Station for an additional 20 years under 10CFR Part 54. This SEIS includes the NRC staff's analysis that considers and weighs the environmental impacts of the proposed action, the environmental impacts of alternatives to the proposed action, and mitigation measures available for reducing or avoiding adverse impacts. It also includes the staff's recommendation regarding the proposed action.

The recommendation of the NRC staff is that the Commission determine that the adverse environmental impacts of license renewal for OCNGS are not so great that preserving the option of license renewal for energy-planning decisionmakers would be unreasonable. This recommendation is based on (1) the analysis and findings in the GEIS; (2) the ER submitted by AmerGen; (3) consultation with other Federal, State, and local agencies; (4) the staff's own independent review; and (5) the staff's consideration of public comments.

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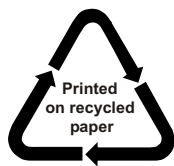
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